BEFORE THE

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

APPLICATION OF DOMINION ENERGY SOUTH CAROLINA, INCORPORATED FOR ADJUSTMENT OF RATES AND CHARGES	**)))))**	**DOCKET NO. 2020-125-E**

SURREBUTTAL TESTIMONY AND EXHIBITS

OF

MARK E. GARRETT

ON BEHALF OF

THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES (“DOD-FEA”)

December 17, 2020

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 4028 Oakdale Farm Circle, Edmond, Oklahoma 73013.

Q: WHAT IS YOUR PRESENT OCCUPATION?

A: I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation, and consulting services.

Q: DID YOU FILE DIRECT TESTIMONY AND EXHIBITS IN THIS PROCEEDING?

A: Yes. I filed direct testimony and exhibits with the Public Service Commission of South Carolina ("Commission") on behalf of the United States Department of Defense and All Other Federal Executive Agencies ("DOD-FEA").

Q: WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A: The purpose of my surrebuttal testimony is to address revenue requirement, cost of service, and rate design issues raised in the rebuttal testimony filed on behalf of Dominion Energy South Carolina, Inc. ("DESC" or the "Company"). I address the rebuttal testimony of DESC witnesses Iris N. Griffin, Kevin R. Kochems, Regina J. Elbert, John J. Spanos, Keith C. Coffer, Alison M. Nawrocki, and Allen W. Rooks.

II. REVENUE REQUIREMENT

II. A. REVISED REVENUE REQUIREMENT CALCULATION

Q: IN YOUR VIEW, SHOULD A RATE DECREASE BE ORDERED IN THIS CASE?

A: Yes, based upon on the issues raised by DoD-FEA witnesses in conjunction with two significant adjustments by the ORS, a **rate decrease** is justified as shown in Table 1 below:

Table 1: Summary of Adjustments (Thousands)

DoD-FEA Adjustments:		
Company's Requested Rate Increase	$	178,234
Rate Base Adjustments:		
Storm Reserve Rider		636
Cash Working Capital		(11,517)
Construction Work in Process		(34,401)
Cost of Capital Adjustments:		
Capital Structure		(3,037)
Return on Equity		(42,985)
Operating Income Adjustments:		
Short-Term Incentives		(5,651)
Payroll Tax on Short-Term Incentives		(490)
Long -Term Incentives		(916)
Storm Reserve Rider		(9,840)
Vegetation Management		(3,519)
Turbine Overhaul		(5,009)
Unrecovered Plant Amortization		(10,512)
Critical Infrastructure Protection Costs		(2,380)
Property Related EDIT Amortization		(21,684)
Total Adjustments		(151,306)
DoD-FEA Recommended Rate Increase	$	26,926
ORS (Major) Adjustments		
Depreciation (Thompson p. 9)	$	(14,000)
Summer Cancellation Debt (Thompson p. 6)		(32,000)
ORS Major Adjustments not Proposed by DoD-FEA	$	(46,000)
Rate Decrease (DoD-FEA with ORS Major Adjustments)	**$**	**(19,074)**

As shown in Table 1 above, adjustments recommended in direct testimony by DoD-FEA witnesses result in a $26.9M rate increase (a significant reduction from the Company's proposed $178.2M increase). However, the DoD-FEA calculation did not take into account two major areas of adjustment that have been proposed by the ORS, which relate to: (1) depreciation and (2) the regulatory treatment of the Summer Cancellation Debt, both of which are addressed by ORS witness Thompson. If each of these adjustments is adopted in addition to the adjustments proposed by DoD-FEA witnesses, the combined impact is a rate **decrease** of ($19.074M).

II. B. CONSTRUCTION WORK IN PROGRESS ("CWIP")

Q: PLEASE DESCRIBE THE COMPANY'S POSITION REGARDING YOUR RECOMMENDATION THAT THE COMMISSION EXCLUDE A PORTION OF THE REQUESTED CWIP?

A: Company witness Iris N. Griffin submitted rebuttal testimony regarding the CWIP issues. Ms. Griffin's position rests on three main assertions. First, Ms. Griffin erroneously claims that I recommend that the Commission "not allow a return on CWIP in rates."[1] Second, she suggests that the Commission's prior allowance of CWIP "in multiple orders since the 1980s" should serve as justification for the Company's request in this proceeding.[2] Finally, she asserts that including CWIP in rates actually saves ratepayers money.[3] I respectfully disagree with Ms. Griffin's assertions for the reasons set forth below.

[1] See Rebuttal Testimony of Iris N. Griffin at page 11, lines 6-8.
[2] Id. at page 11, lines 9-19.
[3] Id. at pages 12-14.

Q: IS IT ACCURATE TO SAY THAT YOU RECOMMEND THAT THE COMMISSION "NOT ALLOW A RETURN ON CWIP" IN RATES?

A: No. Ms. Griffin's testimony mischaracterizes my recommendation. It is not my recommendation that the Commission disallow all CWIP requested by the Company. Instead, I recommend that the Commission limit the amount of CWIP allowed in rates to include the CWIP at the end of the test year that is actually completed and in service by September 30, 2020, nine months after test year end. This results in the inclusion of approximately $220 million of CWIP in rates.[4] As such, a more accurate description of my position is that the Commission should adopt a ***reasonable cut-off*** for the Company's requested CWIP by allowing amounts in service by September 30, 2020, but disallowing recovery of CWIP beyond this reasonable cut-off. My recommendation provides important safeguard for ratepayers.

Q: WHY DOES LIMITING THE AMOUNT OF CWIP INCLUDED IN RATES PROVIDE A SAFEGUARD FOR RATEPAYERS?

A: Including CWIP in rate base is a departure from traditional ratemaking principles, particularly the "used and useful" concept. The "used and useful" standard provides a safeguard to ratepayers because it requires that "only plant currently providing or capable of providing utility service to the consuming public is allowed in rate base."[5] This criterion is interpreted differently by various regulatory commissions, and can be applied

[4] See Garrett Direct Testimony of Mark Garrett at page 63, line 14, through page 64, line 3.
[5] See Robert L. Hahne and Gregory E. Aliff, Accounting for Public Utilities §4.03 (Matthew Bender).

differently to address the particular circumstances of each utility, however, it is important to recognize that the regulatory policy of including project construction costs in rate base before the project is actually providing utility service shifts a meaningful level of risk from the utility to the ratepayers.

Q: PLEASE ADDRESS MS. GRIFFIN'S ASSERTION THAT THIS COMMISSION HAS CONSISTENTLY ALLOWED CWIP IN RATES SINCE THE 1980s.

A: In her rebuttal testimony at page 11, Ms. Griffin includes a list of decades-old cases which purportedly included CWIP in rates. However, her analysis does not explain the Commission's rationale as to why CWIP was allowed. She also provides no information about how much CWIP was included in those cases, nor any information about offsetting adjustments the Commission may have required. Moreover, it is noteworthy that Ms. Griffin makes no reference to the CWIP treatment in the South Carolina Electric & Gas Company (SCE&G) proceedings during the construction of the V.C. Summer Nuclear Stations, perhaps because it presents a prime example of why regulatory commissions should proceed very cautiously when including CWIP in rates. In short, testimony that only makes the blanket assertion that the Commission in the past has allowed CWIP in rates in prior proceedings is not a compelling reason to include the entire amount of CWIP sought by the Company in this case. Ms. Griffin cites no regulation or statute that would require the inclusion of CWIP in rates. In the absence of any such authority, I believe the Commission should adopt my recommendation which provides a very reasonable middle-ground position for the inclusion of CWIP in rates.

Q; DO YOU AGREE WITH THE COMPANY'S CLAIM THAT INCLUDING CWIP IN RATES ACTUALLY SAVES RATEPAYERS MONEY?

A: No. There is virtually no scenario under which this assertion, from a financial perspective, is true. When consideration is given to the time value of money (with all other matters held constant) the cost to ratepayers is virtually the same. However, the amount of risk borne by ratepayers is substantially greater. Ms. Griffin's cost analysis is most likely based upon theoretical or academic examples (as opposed to real-world scenarios) in which: (1) the utility's AFUDC rate is the same as its full weighted average cost of capital (rate base return); (2) the discount rate of the ratepayers is the same as the WACC return of the utility (which is never the case); (3) there is virtually no period of time between when the plant goes into service and when it is included in rates (which is almost never the case), and (4) ratepayers stay on the system for the entire life of the assets in question. The more pragmatic approach recognizes that there is virtually no scenario where including CWIP in rates would be beneficial to ratepayers. When one takes into account the risk that ratepayers may pay for plant being constructed that may not actually go into service, as with the V.C. Summer project, it is difficult to see why including high levels of CWIP in rates is better for ratepayers. On the other hand, there is no doubt whatsoever that maximizing the level CWIP in rates is beneficial for shareholders.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission exclude CWIP not in service by September 30, 2020. This represents a reasonable compromise whereby not all CWIP is excluded, but CWIP that was not in service within nine months after test year end is excluded from rate base.

II. C. <u>CASH WORKING CAPITAL ADJUSTMENT</u>

Q: HAS THE COMPANY FILED REBUTTAL TESTIMONY REGARDING YOUR RECOMMENDATIONS ON ITS CASH WORKING CAPITAL ("CWC") REQUEST?

A: Yes. Company witness Kevin R. Kochems filed rebuttal testimony regarding my recommendation that the Commission should adopt the policy applied in many states that a lead-lag study is essential if the Company seeks to include a positive cash working capital adjustment in its rate base, and that without a lead-lag study, the Company's cash working capital should be set at zero. As I explained in my direct testimony, a well-run utility that uses modern-day cash management techniques will almost always have a negative CWC balance. In his rebuttal testimony, Mr. Kochems raises the following points:

1. He asserts that lead-lag studies are "extremely complex and expensive" and customers ultimately have to pay for them.[6] In support of this position, he references a 1996 order, and cites to three other cases in which the Commission has either approved or allowed the use of the 1/8th method.[7]

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[6] Rebuttal Testimony of Kevin R. Kochems, p. 8, lines 2-4.
[7] Rebuttal Testimony of Kevin R. Kochems, p. 8, line 15- p.9, line 4.

2. He asserts that the Commission has never required the Company to prepare a lead-lag study and has on multiple past occasions rejected the urgings of the Department of Consumer Affairs to do so.[8] For support, he references a 1984 order in which the Commission determined not to require a lead-lad study "at this time."[9]

3. He points out that the Commission previously determined that a lead-lag study performed in a 1988 case did not provide a better approximation of cash working capital needs than the 1/8th method.[10]

4. He notes that the Federal Energy Regulatory Commission ("FERC") allows the use of lead-lag studies and the 1/8th method, and discusses the rationale set forth in a 1979 FERC decision.[11]

5. He argues that in its working capital computation the Company included the Average Tax Accrual balance of ($128M) as a reduction to rate base and this amount exceeds the $111M Working Cash balance, which therefore results in a negative cash working capital balance.[12]

6. Finally, he suggests that because a lead-lag study is "time-consuming," such a study cannot be performed at this point in the process. He therefore requests that if the Commission determines that a lead-lag study would be appropriate, the Company respectfully requests that requirement be implemented in the Company's next general rate case.[13]

[8] Id., p. 9, lines 5-13.
[9] Id., p. 9, line 13.
[10] Id., p. 9 lines 14-17
[11] Id., p.10, lines 7-20.
[12] Id., p. 13, lines 3-9.
[13] Rebuttal Testimony of Kevin R. Kochems, p. 9, line 18- p.10, line 6.

I will address each of Mr. Kochems' specific concerns in the discussion below. However, I would note that none of his arguments refute the overarching issue raised in my direct testimony—that modern cash management techniques and technologies have reduced the cash working capital requirements for utility companies significantly. Cash working capital is the amount of cash which a utility needs in daily operations to pay its operating expenses. This is the amount a utility claims it needs to bridge the timing gap between when expenses are incurred and when revenues are received. In order to include cash working capital in rate base, most regulatory commissions require that a utility provide a "lead-lag" study to show that the company actually has a lag between expenses and receipts of revenue. This is because regulators now recognize that while the 1/8 method may have once provided a fairly close approximation of a utility's CWC needs, the method no longer provides a sufficiently accurate justification for a utility to include a positive CWC balance in rate base.

Q: HOW DO YOU RESPOND TO MR. KOCHEMS' ASSERTION THAT LEAD-LAG STUDIES ARE EXTREMELY COMPLEX AND EXPENSIVE?

A: With current accounting methods and systems available to a utility the size of DESC, the preparation of a lead-lag studies is a straightforward and relatively inexpensive process. As I pointed out in my direct testimony, from ratepayers' perspective, it is extremely cost-effective compared with the amount of CWC the Company seeks to include in rate base. Based on my experience if performed by an outside consultant, the initial study should not cost more than approximately $75,000, but in truth, a utility the size of DESC should have the resources and expertise to perform a lead-lag study by in-house personnel at virtually no additional cost to ratepayers.

Q: HOW DO YOU RESPOND TO MR. KOCHEMS' CLAIM THAT THE COMMISSION HAS ON MULTIPLE PAST OCCASIONS REJECTED THE URGINGS OF THE DEPARTMENT OF CONSUMER AFFAIRS TO RELY ON LEAD-LAG STUDIES?

A: The case Mr. Kochems cited for this proposition is a 1984 case, nearly forty years old, so I would not rely heavily on that case as precedent, however, I do not doubt Mr. Kochems if he says there have been other occasions. Nevertheless, the case that he cited merely stated that the Commission would not require a lead-lag study "at this time," leaving the door open to revisit its decision. I would encourage the Commission to revisit its prior decisions regarding the use of lead-lag studies. In my opinion, ratepayers are paying materially higher rates for a cash working capital requirement that simply does not exist. A lead-lag study would show this to be the case.

Q: WHAT ABOUT THE ASSERTION THAT THE COMMISSION DETERMINED IN A PRIOR CASE THAT A LEAD-LAG STUDY PERFORMED IN A 1988 CASE DID NOT PROVIDE A BETTER APPROXIMATION OF CASH WORKING CAPITAL NEEDS THAN THE 1/8TH METHOD.

A: I cannot speak to the specific facts of that case, but I can say that here a lead-lag study would result in a much better approximation of cash working needs for the Company than a 1/8th method would yield. A 1/8th method, or 45-day method as it is sometimes called, assumes that all expenses of the utility are paid 45 days before payment for those services is received from ratepayers. This simple "rule of thumb" formula for the calculation of cash working capital requirements is seldom used for most modern-day utilities. As explained in the Hahne-Aliff treatise,

> In recent years, more sophisticated accounting systems have allowed utilities to be more efficient managers of cash. Consequently, in many cases, cash working capital requirements have been reduced substantially. This has led many to question the validity of the results produced by the 1/8 formula approach, resulting in increased use of the lead-lag study approach.[14]

Typically, with modern cash management practices a utility generally pays for its goods and services in about the same way ratepayers pay for theirs – in the month following the month in which the services were provided. There are some exceptions. Some payroll is paid on a monthly basis but other payroll is paid on a weekly or biweekly basis. So, the utility may be advancing payment for payroll costs in some situations. On the other hand, however, many times the utility receives cash from ratepayers well in advance of its payment of related expenses. For example, interest on long-term debt is received from ratepayers on a monthly basis but is paid out by the utility on a semi-annual basis, long after the cash has been received from ratepayers. Likewise, ratepayers pay their share of the property tax expense on a monthly basis, but the utility makes its payment in the following year. For these expenses, ratepayers are providing cash to the utility far in advance of when the utility remits its payments. In other words, there are very few

[14] See Robert L. Hahne and Gregory E. Aliff, Accounting for Public Utilities §5.04 [1] (Matthew Bender).

expenses for which the payment for the service is made before the service is provided. Yet the 1/8th method assumes that every expense is pre-paid. That is simply no longer the case for most utility expenses. In today's environment, payments for goods and services are made, almost universally, after the goods and services have been provided.

Q: PLEASE ADDRESS MR. KOCHEMS' TESTIMONY REGARDING THE FERC'S TREATMENT OF CWC.

A: On page ten of his testimony, Mr. Kochems includes an excerpt from a 1979 FERC decision which indicates that, at that time, the 1/8 method produced a reasonable result without the cost of performing a lead-lag study. However, as indicated in my direct testimony, this is no longer the prevailing view of most regulatory commissions. The FERC's current rule on CWC for natural gas companies requires a fully developed lead-lag study, as follows:

> **§ 154.306 Cash working capital.**
> A natural gas company that files a tariff change under this part may not receive a cash working capital adjustment to its rate base unless the company or other participant in a rate proceeding under this part demonstrates, **with a fully developed and reliable lead-lag study**, a net revenue receipt lag or a net expense payment lag (revenue lead). Any demonstrated net revenue receipt lag will be credited to rate base; and, any demonstrated net expense payment lag will be deducted from rate base.[15]

Moreover, in my view it should not be particularly relevant to this Commission what the FERC may allow for the electric utilities it regulates in the wholesale markets.

[15] See 18 CFR §154.306- Cash working capital. (Emphasis added).

Q: DO YOU AGREE THAT, IN ITS WORKING CAPITAL COMPUTATION, THE COMPANY INCLUDED THE AVERAGE TAX ACCRUAL BALANCE OF ($128M) AS A REDUCTION TO RATE BASE AND THIS AMOUNT EXCEEDS THE $111M WORKING CASH BALANCE, RESULTING IN A NEGATIVE CASH WORKING CAPITAL BALANCE?

A: No. The average tax accruals should be a deduction to rate base. That balance represents money collected from ratepayers that will be passed on to the taxing authorities at some point in the future. While in the Company's possession, it represents cost-free capital and should be used to reduce rate base. The same is not true of the $111 cash balance. There is no such balance. It is a fictional number made up by multiplying operating expenses times eight. In other words, you cannot use a fictional cash number to offset a real tax liability (one that should be a reduction to rate base) and claim that the net working capital is negative by $27M, when the amount should be closer to $128M.

Q: WHAT ABOUT MR. KOCHEMS' SUGGESTION THAT BECAUSE A LEAD-LAG STUDY CANNOT BE PERFORMED AT THIS POINT IN THE PROCESS, IF THE COMMISSION DETERMINES THAT A LEAD-LAG STUDY WOULD BE APPROPRIATE IT SHOULD BE IMPLEMENTED IN THE COMPANY'S NEXT GENERAL RATE CASE.

A: I believe it would be appropriate for the Commission to set the Company's CWC at zero in this case. However, I also believe that in light of the history of allowing the 1/8th method in prior cases, the Commission could order the Company to present a lead-lag study in its next rate case along with the 1/8th method, so the Commission could determine if the 1/8th method truly does present a reasonable representation of the Company's CWC needs.

II. D. ANNUAL INCENTIVE COMPENSATION ("AIP") ADJUSTMENT

Q: DID THE COMPANY PROVIDE REBUTTAL TESTIMONY ON THE COMPANY'S INCENTIVE COMPENSATION PLANS?

A: Yes. Company witness Regina J. Elbert provides rebuttal testimony to DoD-FEA, ORS and DCA witnesses that recommend disallowance of the Company's incentive plan costs related to financial performance measures. With respect to the short-term annual cash incentives, Ms. Elbert's rebuttal testimony is focused primarily on the premise that financial incentives provide certain benefits to customers. Assuming for argument sake that this assertion is true, there is still no doubt that financial incentives also strongly promote shareholders' interests, and on balance, benefit shareholders ***more*** than they do customers. That being the case, my recommendation that the Commission order an ***equal sharing*** of incentive costs between customers and shareholders is very reasonable and consistent with the consensus view of commissions across the country.

Q: WHAT DOES MS. ELBERT SAY ABOUT LONG-TERM STOCK INCENTIVES?

A: Ms. Elbert argues that the same justifications for the annual incentive plan apply to the long-term plan. She further asserts that long-term incentive compensation is a "standard executive benefit in the utility industry and in industries across the country." She does not mention the fact that this standard executive compensation is standardly ***excluded*** by most regulatory commissions across the country. As discussed in my direct testimony, in our survey of the western states, 20 of the 24 states tend to exclude all or virtually all long-term stock-based incentive pay, either through an outright ban on stock-based incentives or through applying the financial performance rule, which has the effect of excluding long-term earnings-based and stock-based awards. These states include Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota, Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. In the other four states surveyed, Alaska, Iowa, Montana and Nebraska, the issue just has not been addressed. In the four states surveyed in the east – Michigan, Illinois, Wisconsin and Kentucky – all four disallow financial-based long-term incentives. The bottom line is that of the 28 states survey, we could find no state that allows recovery of long-term stock incentives in rates.

Q: WHAT DO YOU RECOMMEND?

A: Financial-based incentives benefit shareholders more than they do ratepayers. For ratemaking purposes, this means that shareholders should be responsible for these costs. The Company's annual incentive plan is strongly tied to financial measures and as a result I recommend that 50% of the plan costs be disallowed. The Company's long-term plan is entirely tied to financial measures and as a result I recommend that 100% of the plan costs be disallowed.

II. E. <u>CANADYS UNITS 2 AND 3 AMORTIZATION (UNRECOVERED PLANT)</u>

Q: DID THE COMPANY PRESENT ANY REBUTTAL TESTIMONY ADDRESSING YOUR RECOMMENDATION THAT THE COMPANY SHOULD RECOVER THE REMAINING COSTS OF THE RETIRED CANADYS UNITS OVER A 40-YEAR RECOVERY PERIOD?

A: Yes. My recommendations regarding the regulatory treatment of the unrecovered plant costs were addressed by Mr. Spanos, the Company's depreciation expert, and by Company witness Keith C. Coffer. I will address their rebuttal testimonies in turn.

Q: DID MR. SPANOS RAISE LEGITIMATE CRITICISMS WITH RESPECT TO YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE REGULATORY TREATMENT FOR THE RETIRED CANADYS UNITS?

A: No. Mr. Spanos is a depreciation expert, not a ratemaking expert. His expertise deals with the depreciation treatment for plant that is in service. However, once plant is no longer in service, and the remaining balance of the plant is amortized, not depreciated, the depreciation rules are no longer applicable. The types of criticisms Mr. Spanos raises are misplaced. Amortization of retired plant is purely a ratemaking question, not a depreciation question. Mr. Spanos' observations are based on his perspective as a depreciation expert, however, the Commission is not constrained to inapplicable depreciation rules as Mr. Spanos' testimony suggests.

Q: WHAT POINTS DID MR. SPANOS RAISE REGARDING YOUR RECOMMENDATIONS FOR THE RATEMAKING TREATMENT FOR APPROPRIATE AMORTIZATION OF THE RETIRED PLANTS?

A: Mr. Spanos testified as follows:

1. Witness Mark Garrett has selected a 40-year amortization period to recover all remaining costs, which has no basis.[16]

2. General Instruction 22A of the USOA (Uniform System of Accounts) states that: Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.[17]

3. Mr. Garrett's recommendation would result in customers paying much more for the assets over a recovery period of 40 years rather than the currently planned recovery through approximately 2026.[18]

Q: DO YOU AGREE WITH MR. SPANOS' FIRST ASSERTION THAT YOUR RECOMMENDED 40-YEAR AMORTIZATION HAS "NO BASIS"?

A: No. I provided a basis in my testimony for the recommended amortization period of 40 years, which was the average useful life of a natural gas combined cycle proxy replacement plant. My recommendation reflects a perfectly rational period of time over which to recover the remaining costs of a prematurely retired generation unit.

[16] Rebuttal Testimony of John J. Spanos at page 49, lines 6-7.
[17] Id. at page 50, lines 8-11.
[18] Id. at page 51, lines 8-11.

Q: MR. SPANOS EMPHASIZES THE FACT THAT THE UNIFORM SYSTEM OF ACCOUNTS ("USOA") REQUIRES THAT PROPERTY BE DEPRECIATED OVER THE USEFUL LIFE OF THE PROPERTY. DOES THIS REQUIREMENT APPLY TO THE RETIRED CANADYS UNITS?

A: Absolutely not. General Instruction 22A applies to plant that is in service providing electricity to customers. It does not apply to retired plant that is no longer being depreciated. General Instruction 22A states:

> 22. Depreciation Accounting.
>
> A. Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value *of depreciable property* over *the service life of the property*.[19]

Here, the Canadys Units are *not* depreciable property, because they are retired, and they have *no service life* any longer, because they are not in service. In other words, Mr. Spanos is discussing a rule that does not apply to retired plant. Once a plant is retired and no longer in service, it is not subject to the depreciation rules. The stranded costs of a retired plant are not depreciated, they are amortized. And, amortization periods are *exclusively* left for regulatory commissions to decide. Regulators can choose any amortization period they believe to be appropriate and are not constrained in any way by the accounting rules that specifically apply to depreciable plant in service.

Q: IS MR. SPANOS' ASSERTION CORRECT THAT YOUR RECOMMENDATION RESULTS IN HIGHER COSTS TO CUSTOMERS?

[19] See 18 CFR Part 101-Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act., General Instruction 22A (Emphasis added).

A: No, absolutely not. When the time value of money is taken into consideration, as it must be in any financial analysis, the cost to customers is exactly the same under either a 6-year or a 40-year amortization of the remaining balance. In other words, the present value of $57.2M (the balance at March 2021) recovered over a 6-year period discounted at the utility's weighted average cost of capital ("WACC") is exactly the same as the present value of $57.2M recovered over a 40-year period discounted at the utility's WACC. In both cases, the present value of either stream is $57.2M.

Q: HOW DO YOU RESPOND TO THE REBUTTAL TESTIMONY OF MR. COFFER REGARDING YOUR RECOMMENDATION FOR AMORTIZATION OF THE COSTS ASSOCIATED WITH THE RETIRED CANADYS UNITS?

A: Company witness Keith C. Coffer testifies that "Mr. Garrett's proposal is significantly more costly for customers over the long-term. By extending the recovery period, the regulatory asset balance amortizes more slowly resulting in a higher rate base over an expanded period of time."[20] As addressed in my surrebuttal testimony to Mr. Spanos, this assertion is clearly incorrect and without merit. When the time value of money is taken into consideration, as it must be, the present value of a longer amortization period or a shorter amortization period is the same, so long as the same return is applied to both streams.

[20] Rebuttal Testimony of Keith C. Coffer, at page 7, lines 4-7.

II. F. <u>PROPERTY RELATED UNPROTECTED EDIT</u>

Q: WHAT ISSUES DID THE COMPANY RAISE REGARDING THE AMORTIZATION OF PLANT-RELATED UNPROTECTED EXCESS DEFERRED INCOME TAX ("EDIT")?

A: Lane Kollen for ORS and I for DoD-FEA both testified that the Commission could amortize the plant-related unprotected EDIT back to ratepayers over a much shorter time period than the ARAM period currently being used. However, the Company suggests that we ***both*** computed two different numbers and it is not clear how the computations were performed. Actually, the differences in our calculations are minor as discussed below.

In comparing our calculations, there is a $3.6M difference in our beginning balances, because Mr. Kollen starts with a balance at 12-31-20 of $121.7M and I start with the balance at 3-31-21 of $125.3M. This results in an annual difference in our 5-year amortizations of about $0.8M. On a jurisdictional basis, the difference is about $0.5M. Mr. Kollen calculates an annual jurisdictional amortization of $21.2M compared to our amortization of $21.7M. He then shows his recommended annual amortization net of tax at $15.9M, because he makes his adjustment to income tax expense which then gets grossed up for tax in the ultimate revenue deficiency/excess calculations. I gross our number up for tax in the adjustment itself, not in a separate calculation on the combined adjustments. The bottom line is, the ultimate impact of the ORS adjustment on the revenue requirement is $21.2M per year and the ultimate impact of our adjustment is $21.7M per year, and this difference exists because we are started with slightly different balances. The Commission merely needs to order DESC (1) to start with the actual balance for the plant-related EDIT that exists at the start of the rate-effective period (the date new rates go into effect), and (2) to amortize that balance over a 5-year period.

Q: DOES THE COMPANY DISPUTE THE FACT THAT THE PLANT-RELATED EDIT CAN BE REFUNDED OVER WHATEVER PERIOD THE COMMISSION CHOOSES?

A: No. The Company's witness, Alison M. Nawrocki, admits that the Commission can refund unprotected EDIT over whatever period it deems reasonable. The flow of these amounts (which I will refer to hereafter as "unprotected" EDIT) can occur at whatever rate the regulator deems reasonable and appropriate.

Q: ARE THERE OTHER ISSUES IN THE COMPANY'S REBUTTAL TESTIMONY THAT NEED TO BE ADDRESSED?

A: Yes. Nawrocki disagrees with our recommendation to refund the unprotected EDIT over a shorter period than the ARAM period, which extends over the life of the assets. The sole reasoning is that our approach deprives ratepayers in later years of these refunds. Her recommendation does not provide the EDIT to customers in later years who are paying for the plant costs through depreciation expense. Her concern on this issue is completely misplaced.

The goal with EDIT refunds is to get the money back to the customers who over-paid the taxes. The customers who over-paid the taxes are all customers of the past, not customers in the future. In other words, customers on the system before the new tax law went into effect January 1, 2018 are the customers who paid the 35% tax rate that was changed to 21% January 1, 2018. These are the customers entitled to the refunds, not customers on the system 25 years from now. With EDIT, the idea is to get the money back to the customers who over-paid it as soon as possible. The only exception is protected EDIT that must be refunded over the ARAM period so as not to violate the IRS normalization rules. Our recommendation accomplishes the objective of returning the refunds to customers in timely manner that is consistent with the IRS normalization rules.

III. COST OF SERVICE

Q: DOES THE COMPANY ADDRESS THE AVERAGE AND PEAK ALLOCATION METHODOLOGY FOR PRODUCTION PLANT RAISED BY MR. DISMUKES?

A: Yes. Company witness Mr. Kochems addresses the recommendation by Mr. Dismukes that the Commission adopt the Average and Peak cost allocation methodology for allocating production plant costs, as opposed to the Coincident Peak method used by the Company for the last 38 years.[21] In response to Mr. Dismukes' recommendation, Mr. Kochems points out the importance of consistency in the rate setting process. He refers to consistency as a ratemaking cornerstone. He also states that conducting business without consistency results in improper swings in rates between customer classes.[22]

Mr. Kochems explains that the reason the Coincident Peak cost allocation has been the longstanding method is because it is "the most consistent with the actual load analysis

[21] Rebuttal Testimony of Kevin R. Kochems, p. 2, line 18—p. 3, line 2.
[22] Id., p. 2, lines 19-20.

and operation of the Company's electric system."[23] He further notes that changes to allocation methods, such as those proposed by Mr. Dismukes, could have significant and long-term impacts on customers, and that such changes should be thoroughly evaluated before such a change is made.[24]

Q: DO YOU AGREE WITH MR. KOCHEMS?

A: Yes. Mr. Kochems is correct on this point. Stability, consistency, and predictability are fundamental attributes in the regulatory process. Utility customers, especially large industrial customers, rely on consistent and predictable regulatory decisions, and they organize their business decisions accordingly.

It is particularly important to understand that large manufacturing firms make their decisions to locate, expand or contract in a state such as South Carolina based in part, sometimes in large part, on the price of electricity and the regulatory environment in that state. Changing from a reasonable allocation methodology such as Coincident Peak, which the Company states is most consistent with the actual load analysis operation of its system, to a *business-adverse* method like Average and Peak, would be contrary to economic development goals in the state. In light of the impact of the COVID-19 pandemic on businesses, this is a particularly bad time to create unnecessary instability for South Carolina's industry.

The bottom line is this, regulatory consistency is important and should be maintained unless there is a demonstrable reason that a change is needed. This does not

[23] Id., p.3, lines 16-18.
[24] Id., p. 3, lines 5-10.

appear to be the case with Mr. Dismukes' request for a new cost of service allocation methodology. I agree with Mr. Kochems that allocating production plant costs on a Coincident Peak basis remains the appropriate and valid allocation methodology. Before the Commission considers adopting a new methodology, there should be a showing of a change in circumstances warranting that change. No such change has been identified.

Q: IS THE AVERAGE AND PEAK METHOD A LEGITIMATE METHODOLOGY FOR THE ALLOCATION OF PRODUCTION PLANT?

A: No. Average and Peak is a methodology designed to reduce costs allocated to the low-load factor customers, the most expensive customers to serve, at the expense of the high-load factor customers, the most inexpensive customers to serve. In other words, it is a method designed to reduce residential rates at the expense of industry. These methodologies designed to subsidize residential customers are ill-advised in the long run because they ultimately tend to push industry out of the service territory which then increases costs to everyone.

Q: IS THE AVERAGE AND PEAK METHOD A WIDELY USED METHOD?

A: No. In my experience, it is a method that fell from favor long ago and is now all but extinct, at least in the western states. A recent survey of the 24 Western states taken by the Garrett Group in 2013 showed that only one state, Arizona, utilizes the Average and Peak method, and for only two utilities in that state. The Garrett Group's 2013 Production Cost Allocation Survey is attached as Exhibit ___(MG-6). I also know for a time Arkansas allowed the use of the Average and Peak method for Entergy Arkansas, Inc. but a state statute passed in 2015 prescribed the use of a 4CP-A&E method going forward to promote economic development and job growth. As such, the Average and Peak method is no longer used in Arkansas.

Q: WHY IS THE COMPANY'S COINCIDENT PEAK METHOD A SUPERIOR METHOD COMPARED TO THE AVERAGE AND PEAK METHOD?

A: Mr. Kochems is correct when he states that the Company builds its Production and Transmission assets to support the system peak. In other words, plant investment is driven by peak demand. Consequently, an allocation methodology that classifies all production plant costs as being demand-related, as the Coincident Peak method does, should be used. An allocation methodology which effectively classifies a significant portion of demand-related costs as being energy-related costs instead is a flawed methodology that yields erroneous results.

Q: WHAT DO YOU RECOMMEND?

A: I recommend that the Commission continue its long-standing use of the Coincident Peak methodology. If the Commission wants to improve on that methodology for the sake of economic development it should examine whether a 15-minute interval to establish the system peak would be superior to the 4-hour interval now used by the Company. A 4-hour interval is a fairly diluted version of the system peak and a 15-minute interval, or even a 1-hour interval, would be a better representation of how the system was built to meet peak demand. I recommend that the Commission ask DESC to provide its cost of service study in the next rate case showing production plant allocated with both the 4-hour CP it uses now and a 15-minute CP as well.

IV. RATE DESIGN

IV. A. POWER FACTOR CORRECTION

Q: DID THE COMPANY PRESENT REBUTTAL TESTIMONY TO YOUR RECOMMENDATION THAT THE POWER FACTOR FOR THE LARGE CUSTOMER CLASSES BE INCREASED FROM 85% TO 90%?

A: Yes. My recommendations are addressed by Company witness Allen W. Rooks. In his rebuttal testimony, Mr. Rooks admits that a higher power factor would promote efficient use of power, minimize line losses and reduce costs to other customers.[25] However, he opposes the recommended increase in the power factor because it would increase rates to some large customers or require them to spend money to increase their power factors to 90%.[26] He estimates that an additional $2.0 to $2.5M would be imposed on certain Large General Service customers with power factors between 85% and 90%.[27]

Q: ARE THESE GOOD REASONS TO NOT CORRECT THE POWER FACTOR, AT LEAST GRADUALLY AS YOU RECOMMEND?

[25] See Rebuttal Testimony of Allen W. Rooks, at page 9, lines 13-17.
[26] Id. at page 10, lines 5-8.
[27] Id. at page 10, lines 15-19.

A: No. What Mr. Rooks fails to mention is that a correction in the power factor to 90% would also lower costs to other customers in the class with power factors higher than 85%. So, a correction to 90% would raise rates to some customer and lower rates to other customers, but the net effect would be that all customers pay rates closer to the costs they impose on the system. In other words, it would be more appropriate for the Company to correct its power factor and collect from the appropriate customers the costs they are actually causing on the system. An increase to 90% would reduce the subsidy currently being paid to customers with lower power factors.

Q: DOES MR. ROOKS ADDRESS THE FACT THAT DESC CURRENTLY HAS OTHER RATE SCHEDULES WHERE THE POWER FACTOR IS EFFECTIVELY CORRECTED TO 100%?

A: No. In my direct testimony I point out that DESC utilizes a KVA demand billing charge for the Medium General Service and the General Service Time-of-Use Demand rate classes. Use of the KVA demand billing units is the equivalent of correcting to a 100% power factor. Clearly, DESC understands the implications of correcting for power factor and has rate schedules in place that demonstrate it is capable and willing to fully correct for power factor deficiencies. In my direct testimony I recommend that the Commission could require the Company to use a kVA charge in the Large General Service class like it does in the other classes to eliminate the power factor subsidy. Mr. Rooks does not address this recommendation.

Q: WHAT DO YOU RECOMMEND?

A: I believe it would be inappropriate to allow any rate increase to the Large General Service customers without some change to the power factor provision to reduce the subsidy issue. If, on the other hand, the Commission does not impose a rate increase on the Large General Service customers in this case, I think it would be appropriate to leave the Power Factor where it is but to require that the Company, in its next rate case, implement for Large General Service customers either (1) a change in the power factor to 90% or (2) the use of a kVA charge in that class.

IV. B. RATE 23 AVAILABLITY

Q: WHAT IS YOUR RESPONSE TO MR. ROOKS TESTIMONY CONCERNING YOUR PROPOSAL TO ELIMINATE THE SIC AND NAIC REQUIREMENTS AND ESTABLISH A LOAD FACTOR THRESHOLD FOR QUALIFICATION ON THE COMPANY'S INDUSTRIAL POWER SERVICE RATE 23?

A. Mr. Rooks' primary arguments are that the Commission approved the language, it works for the Company and for specific customers, and making any changes would upset the status quo. He also asserts that making any change during a rate proceeding would be inappropriate.

Q: DO YOU AGREE WITH THESE OBJECTIONS?

A: No. With regard to commission approval, it is the very intent of a rate proceeding to review and consider whether there are any appropriate changes needed to approved rate schedules. Moreover, Mr. Rooks does not include any testimony or provide any evidence to justify a lower priced rate for those customers served on the Rate 23. A SIC or NAIC code for a customer does not determine how DESC's costs are incurred. My direct testimony lays out the reasons why the language should be changed. He does not address any of these reasons.

Q: MR. ROOKS STATES THAT THE AVAILABILITY CRITERIA SHOULD NOT BE MODIFIED TO INCLUDE AN ARBITRARY LOAD FACTOR? WHAT IS YOUR RESPONSE?

A: I would say that there is nothing arbitrary about a defined numerical load factor at which a customer would qualify for service. The load factor level should be set based on what the company can prove and provide evidence to support a reasonable threshold at which pricing differentials are justified. The Company should be required to show that there is a cost justification for having a distinction and to also define the breakpoint. What is arbitrary is the current availability criteria in Rate 23 which are without basis from a cost of service standpoint. The current availability criteria allow DESC to provide a lower priced rate to customers in specific industries regardless of that customer's consumption. In other words, the current definitions allow DESC to pick winners and losers.

V. <u>CONCLUSION</u>

Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A: Yes, it does.

Production Cost Allocation Survey 2013
Results By State

Alaska: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222) Alaska has not responded at this time. Alaska Administrative Code requires both the average and excess and peak responsibility (CP) be filed by the electric utility:

> §3 AAC 48.540(e) – Cost-of-Service Methods states that in a cost-of-service study required by this section, demand capacity costs will be considered as follows:
> (1) Each electric utility that sells 100,000,000 kilowatt-hours or more annually shall provide cost-of-service analyses that show the impact of
> (A) allocating demand-related generation and transmission costs to rate classes on the basis of both the peak responsibility method and the average and excess method; and (B) allocating demand-related distribution costs on the basis of the non-coincident peak method.

Arizona: (Corporation Commission, Barbara Keene, Public Utilities Analyst Manager, 602-542-0853) Arizona does not require the use of a particular allocation method by statute or rule. In practice, Arizona utilities use two methods; Arizona Public Service Company (APS) uses the Average and Excess method while UNS Electric Inc. (UNS) and Tucson Electric Power (TEP) use an Average and Peak method with 4-CP based on the 4 summer peaks of June through September. The results of these studies are not stringently followed. The cost of service studies are used as a tool. For example, settlements can result in a generally even, "across the board" percentage increase in rates. The cost of service studies can be used as a starting point for these settlements. In addition, the Commission considers gradualism and other factors in addition to the results of the cost of service studies when setting rates. This issue is no longer very contentious, but current practice resulted from earlier litigated cases which were highly contested by advocates for the residential and industrial classes who argued for 100% energy and 100% demand methods respectively. The current treatments are demonstrated in APS rate cases E-01345A-11-0224 and E-01345A-08-0172 and in the immediate UNS Electric Inc. rate case, Docket No. E-04204A-12-0504.

California: (CPUC, Christopher Danforth, Supervisor DRA – Rate Design, 415-703-1481) In California, electricity generation production costs are allocated to customer classes using marginal cost principles. The energy costs have been allocated using marginal costs that either come from production cost simulation models or market indexes. The generation capacity costs generally are based on a combustion turbine proxy plant. Those costs are often adjusted to reflect the resource balance year, when new capacity would be required, and the costs savings from the new combustion turbine displacing older and less efficient plants. These costs are allocated to time periods using loss-of-load probabilities. Once marginal costs are calculated, they are scaled up or down to reconcile them against the authorized revenue requirement.

Colorado: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) There is no required method in Colorado; the utility may propose any method it choose. However, the Commission's well-established practice is to follow its previous orders. In a recent example, Public Service Company of Colorado (an Xcel Energy company) used a 4-CP Average and Excess method to allocate production costs (see Docket: 09AL-299E, Order: C10-0286).

Hawaii: (PUC, Richard VanDrunen, Engineer, 808-586-2043) Hawaii uses various allocation methods and considers the issue on a case by case basis. However, Hawaii's large utility, Hawaiian Electric Company HECO, has used an Average-Excess Demand Method (AED Method) since 2007 (Docket No. 2006-0386). Cases here tend to result in settlements that divide the dollar amount of any rate increase according to the current percentages paid by the classes. However, in the same 2006 case, the Commission accepted a modification to the classification of non-fuel production O&M expenses from 100% demand-related to partly energy-related. The resulting classification is 60.3% demand and 39.7% energy for these expenses.

Idaho: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho does not have one standard allocation requirement and evaluates the issue case by case. Methods for each of its three major utilities have been set by multiple orders and settlements. PacifiCorp's allocator uses 75% capacity and 25% energy (see PAC-E-10-09). Idaho Power's longstanding use of a Weighted 12CP allocation method based on load factors produces an energy component between 55% and 60%. Avista uses a Peak Credit method to the classes which considers combined cycle turbine production as demand and all above that as energy. This method results in an energy component of about 70%, and is demonstrated in their most recent 2012 rate case: AVU-E-12-08. Avista may propose changing the allocation method in their next rate case in 2015.

Iowa: (Iowa Utilities Board, Barb Oswalt, Senior Utility Analyst, 515-725-7342) The administrative rules related to electric cost of service and rate design are set out in 199 IAC 20.10. Although, the rules do not prescribe a specific allocation method, the Board has determined that the average and excess (A&E) method complies with the rule. Iowa has two investor-owned rate-regulated electric utilities—Interstate Power and Light Company (Interstate) and MidAmerican Energy Company (MidAmerican). In Interstate's most recent rate proceeding (RPU-2010-0001), the Board approved IPL's proposal to continue its use of the A&E methodology for allocating generation costs. IPL noted that it has used the A&E method since 1984. MidAmerican has had a voluntary electric rate revenue freeze in effect since 1997. On May 17, 2013, MidAmerican filed a rate increase request in Docket No. RPU-2012-0004 which includes four separate cost-of-service alternatives. Per the Direct Testimony of Charles B. Rea, the four alternatives allocate generation costs as follows: 1) two of the alternatives use the Hourly Costing Model, 2) one alternative uses A&E with wholesale margins allocated on excess demand, and 3) one alternative uses A&E with wholesale margins allocated on average demand. MidAmerican supports use of the Hourly Costing Model. This docket is pending.

Kansas: (Corporation Commission, Utilities Division, Bob Glass PhD, Chief of Economic Policy (785-271-3356) Kansas uses several allocators including a Peak and Average hybrid as well as 4-CP and 12-CP methods. Kansas production includes coal and nuclear and its consumers include those with significant use that is non-congruent with major demand peaks (e.g. summer irrigation). To fairly share the production cost burden among the classes the commission there uses the various allocators to add an energy component to the allocations. This treatment is not proscribed by statute or rule but is reflected in commission orders and settlements such as the recent Kansas City Power and Light rate case docket 12-KCPE-764-RTS. An open Generic Docket is being developed that will address this issue and others.

Louisiana: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) Louisiana has not responded at this time. In a data response in the immediate Entergy Arkansas rate case: Docket No. 13-028-U, the company states that Louisiana PSC has adopted the 12-CP Production Demand Allocation Factor.

Minnesota: (PUC, Clark Kaml, Rate Analyst, 651-201-2246) Minnesota has not responded at this time. In its last rate case (Docket No. PUC E-002/GR-12-961) Excel Energy in Minnesota (Northern States Power Company) used a "stratification" method to divide Fixed Production Plant into capacity and energy components. The capacity component is allocated "based on customer demand at peak times."

Missouri: (PSC, Robert Schallenberg, Director, Audits, Accounting and Financial Analysis Department, 573-751-7162) MPSC does not endorse any particular allocation method. Cases in Missouri usually settle and settlement methodologies do not have any precedential value.

Montana: (PSC, Will Rosquist, Chief Rate Design and Economics Bureau, 406-444-6359) The Montana PSC does not require use of a specific allocation method. Allocation methods are addressed on a case by case basis. Often, cost allocation issues settle without reference to a particular allocation method.

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Council, Natural Gas Department, NPSC, 402-471-3101) Nebraska has no investor-owned electric utilities; all electric demand is supplied by consumer-owned power districts, cooperatives, and municipalities.

Nevada: Generation production costs are allocated to customer classes using marginal cost principles. The generation capacity costs generally are based on a combustion turbine proxy plant. These costs are allocated to time periods using loss-of-load probabilities. Once marginal costs are calculated, they are scaled up or down to reconcile them against the authorized revenue requirement.

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) New Mexico has no specific requirement for determining the allocation of production costs, and various methods have evolved and been proposed and accepted. The NMPRC regulates three investor-owned electric utilities: Southwestern Public Service Company (SPS), Public Service Company of New Mexico (PNM) and El Paso Electric Company (EPE). SPS, in a pending rate case and in three rate cases filed since 2006, used the 12 CP method for allocating production costs between the New Mexico, Texas and FERC jurisdictions, and the 4 CP method (which includes the 4 peak summer months of June – September) for allocating demand costs among customer classes (see 10-00395-UT). Public Service Company of New Mexico (PNM) in past rate cases has used the 4 CP method, the 12 CP method, and a winter and summer peak method for allocating production demand costs. El Paso Electric Company (EPE) in its most recent rate case filed in 2009 used the 4 CP Average and Excess method, and discussed how that method was more representative of its system costs at that time than the 12 CP method it had used in previous cases.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) The allocation method used in North Dakota varies from company to company. The various methods the companies use are well established and rarely challenged. In general, NDPSC staff does not focus on rate design and class allocations nor does it regularly file testimony on these issues in rate cases. Most cases end in settlement and the class cost of service studies are consulted to arrive at an allocation of any rate increase that slightly weights (increases) the percentage assigned to the residential class in order to gradually bring them to parity with the other classes. Prior to allocation, production costs are "stratified" into capacity and energy components. The cost of a gas turbine peaking plant is used as the lowest cost to meet peak demand. The percentage of the costs to build the state's other 5 types of generation that exceed the price of a peaking plant are considered "energy-related." These percentages are applied to the revenue requirement components of each generation type. The resulting "capacity-related" costs are allocated to the classes with a 4-CP, 12-CP or other method. In the case of Northern States Power these costs are allocated using a seasonal Average and Excess method. This treatment is described in the recent docket, PU-12-813 (see NSP Volume 1, Notice of Petition, Michael Peppin).

Oklahoma: OG&E uses a single coincident peak average and excess method (1-CP AED). They first calculate average demand by taking the total kWh sales divided by the number of hours in a year, 8760. The peak demand is the highest demand expected (OG&E uses a weather normalized peak not the actual peak). The peak demand minus the average demand is the excess portion. PSO uses a 4-CP method. They use the recorded or actual demand of the months of June, July, August and September to allocate production plant.

Oregon: (PUC, George Compton, 503-378-6123) Oregon has two major electric utilities and the allocation method is similar for both. Utilities are required by statute to start with marginal costs when allocating production costs. For Portland General Electric (PGE) marginal costs for demand are considered to be the capital cost of a simple cycle combined turbine peaking plant with a 13% reserve. This capital cost is then allocated to the classes by a 4CP (2 winter and 2 summer peaks) allocator. An energy component is calculated based on 8760 (hr/yr) marginal costs at the hub with some wind cost factored in. The shared sum of these demand and energy components is then used to allocate the imbedded cost of production to the classes. PacifiCorp has asked recently to incorporate a 12CP method as opposed to the 4CP method favored by staff. The issue was not clarified in the settlement. In that case an increase to the residential class was smaller than that to the commercial and industrial classes, but similar to the proportions indicated in the cost of service studies of the company and staff.

South Dakota: (PUC, Brittany Mehlhaff, Utility Analyst, 605-773-8372) Allocation method is not established by statute or rule and can vary by utility and case. Both Ottertail and Xcel have had settlements recently using the 12CP Method for both jurisdictional and class allocation of production cost. In the current Black Hill case, the company has asked to use a 12CP jurisdictional allocator and an Average and Excess method for the class allocations. Northern States, MidAmerican, Northwestern and other South Dakota utilities do not have recently litigated cases.

Texas: (PUC, William Abbott, Director Tariff and Rate Analysis, 512-936-7453) The Texas PUC does not require an allocation method by statute or rule. However, by general precedent the Average and Excess with 4-CP Demand Method is the norm for vertically integrated utilities in Texas. This treatment is demonstrated in the most recent Entergy Texas rate case: Docket No. 39896 in the Order on Rehearing.

Utah: (PSC, Jamie Dalton, Technical Consultant, 801-530-6707) Utah classifies fixed generation costs as 75% related to demand and 25% related to energy and then allocates to the classes using a 12-CP method. This treatment is consistent with prior decisions and supported by analysis which was accepted by the commission in the past. The order in the Rocky Mountain Power rate case docket 09-035-23 filed February 18th, 2010 discusses and accepts this treatment.

Washington: (Utilities and Transportation Commission, Roland Martin, Accounting Advisor, 360-664-1304): Generation and transmission related costs are allocated based on the relative customer class energy and capacity needs. The energy and capacity/demand factors are weighted (e.g. 75/25) based on peak credit methodology. The energy portion is based on each class annual energy as a percentage of total and the demand portion is based on each class contribution to the total peaks (e.g., 12 CP, 200 CP or other system peak measurements). The Commission regulates three electric utilities: Avista, Pacific Power and Light Company (PacifiCorp) and Puget Sound Energy. The peak credit method is used with varying demand/energy weightings. PacifiCorp uses the same 75% demand and 25% energy weighting it uses elsewhere but is proposing to modify the allocation factor in the pending case UE-130043.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Class allocation of production costs use a 12-CP method and are based on 75% Demand and 25% Energy. This is a well-established practice based on Commission orders and approval.